BP Cherry Point Cogen
DEIS Comment - 24

Greater Vancouver Regional District
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File: CP08 01 BPA

Allen Fiksdal, Manager
Energy Facility Site Evaluation Council (EFSEC)
P.O. Box 43172
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Dear Mr. Fiksdal

Re: Comments on the BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement

As the technical lead organization for Canadian air quality agencies, we wish to advise EFSEC of our comments and concerns regarding the *BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement*. These concerns have been identified by the *Interagency Technical Review Team* consisting of staff from the Greater Vancouver Regional District (GVRD), Fraser Valley Regional District (FVRD), B.C. Ministry of Water, Land and Air Protection, and Environment Canada, who reviewed the air quality section of the *Draft Environmental Impact Statement* as well as some additional information provided by the proponent.

The attached report present the issues that we believe were not addressed adequately in the DEIS and/or remain as main concerns for this project. A more detailed analysis of the DEIS and air quality related concerns/issues are provided in Attachment-A of the *Interagency Technical Review Team* report.

Thank you for the opportunity to comment on the proposed *BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement.*

Yours truly,

Hugh Kellas

for Ken Cameron
Manager, Policy and Planning

Attachment

cc Mike Nassichuk, Environment Canada
Hu Wallis, Ministry of Water, Land and Air Protection
Hugh Sloan, Fraser Valley Regional District

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Interagency Technical Review Team Comments on the BP Cherry Point Cogeneration Project – Draft Environmental Impact Statement

(October 29, 2003)

SUMMARY

On September 5, 2003, the Draft Environmental Impact Statement (DEIS) for the proposed BP Cherry Point Cogeneration Project was issued by Washington State Energy Facility Site Evaluation Council (EFSEC). The *Interagency Technical Review Team* consisting of air quality experts from the GVRD, FVRD, Ministry of Water Land and Air Protection, and Environment Canada, met with BP Cherry Point representatives and their air quality consultants on September 15, 2003 to discuss air quality issues identified by the Canadian agencies, and how they were addressed in the DEIS. New information on modelled air quality impacts of the project (e.g. isopleths of ambient air concentrations) and impacts of startup/shutdown practices (which were not included in the Draft EIS) were provided during and after the September 15th meeting.

The following is a summary of issues that the *Interagency Technical Review Team* believe were not addressed adequately in the DEIS and/or remain as main concerns for this project. These findings are based on the review of the air quality section of the Draft EIS, pre-filed testimony, and discussions with the proponent and their air quality consultants:

- **Health Effects:** There is a substantial and growing body of evidence that suggests that adverse health effects would be predicted at particulate matter and ozone exposure levels currently experienced in the Lower Fraser Valley, below current air quality objectives. For example, Bates et al (2003) concluded that: *"Levels of some air pollutants, particularly $PM_{2.5}$ and its wood smoke component, and ozone, in British Columbia are at levels which, on the basis of comparisons with international data, would be predicted to be causing adverse health effects,"* and went on to recommend that: *"...any improvement in air quality for PM or ozone would result in fewer negative health impacts."* (See Attachment-A for further information.) In order to fully describe the health and environmental impacts of the proposed project, the final EIS should analyze the implications of this body of evidence with respect to the project. 1

- **Particulate Matter (PM) Emissions:** Due to the potential implications of the body of evidence mentioned above, and the fact that the *Canada-Wide Standards for Particulate Matter (PM) and Ozone* acknowledge this body of evidence and include commitments to "continuous improvement" and "keeping clean areas clean," PM emissions from the proposed plant are an issue of potential concern. "Maximum Potential" emissions of primary PM from this project are estimated at 262 tons per year, and would be released almost entirely in the form of fine particulate ($PM_{2.5}$). "Expected" emissions which are considered as more representative of actual emissions from the proposed power plant are estimated at 232 tons per year. This has the potential to increase the overall PM_{10} and $PM_{2.5}$ emissions in the LFV airshed by 1.5% and 3%, respectively. The "expected" annual emissions presented in the DEIS, assumes 60% error in the EPA test reference method and subtracts an additional 149 tons per year of PM_{10} from the annual emissions as "PM adjustment". In the absence of additional scientific documentation, it would be difficult to justify such adjustments. 2

It is recognized that the retirement of the old refinery boilers will reduce emissions of other criteria air pollutants (e.g. NO_x and SO_x), which are precursors for fine particulate, and would help reduce the secondary PM formation in the atmosphere. However, there is uncertainty contained in the conversion rate that would affect the amount of secondary PM avoided (or formed) due to the reduction (or increase) in precursor emissions such as NO_x, SO_x and ammonia. This results in an uncertainty in the overall PM impacts of this project. A range of conversion rates should be examined in the final EIS to address the lack of literature on the subject and the uncertainty contained within the conversion rate assumptions. A more detailed analysis of primary PM emissions and secondary PM can be found in Attachment-A. 3

Given the concern around PM, the final EIS should include a more thorough analysis of potential ambient concentrations of PM_{10} and $PM_{2.5}$ than contained in the DEIS. Specifically, although the DEIS presents modeling results for worst-case ambient concentrations of PM (at the worst-case location in Canada), we understand that the models used to generate these results did not take into account the formation of secondary particulate. Because of the potential importance of exposure of Canadian residents to PM at levels below current objectives, the final EIS should include scientifically credible (for this airshed) modeling of worst-case ambient primary and secondary PM concentrations (including secondary particulate formation from in-plume and ambient ammonia). In order to address the worst case, such modeling should continue to ignore any "refinery offsets" or "PM adjustments," as in the DEIS, especially for consideration of short-term exposures. 4

- **Ammonia (NH_3) Emissions:** Ammonia emissions from the proposed plant are also an issue of potential concern. The use of selective catalytic reduction (SCR) control technology to reduce NO_x emissions, is expected to release nearly 175 tons per year of ammonia. While the proponent has provided information to indicate that the maximum predicted ammonia concentration is less than the Acceptable Source Impact Level (ASIL), it would be beneficial to also report the maximum predicted concentration in Canada. In addition, ammonia is a precursor to secondary particles (e.g. ammonium nitrate and ammonium sulfate) in the presence of NO_x and SO_x. As mentioned above, giving a consideration to the formation of additional ambient particulate due to this ammonia source would be useful when assessing the total ambient particulate concentrations (PM_{10} and $PM_{2.5}$) resulting from the project. 5

- **Start-Up Scenarios:** The DEIS modeled worst-case Canadian ambient concentrations of several pollutants. It is our understanding that these worst cases were defined from "maximum potential emission" scenarios, but that these scenarios did not include start-up scenarios. Additional information received from the proponent subsequent to the release of the DEIS suggests that for some parameters (e.g. nitrogen oxides and carbon monoxide), the worst-case scenario for short-term exposures in Canada may be a start-up scenario. Therefore we conclude that in order to most accurately describe the environmental impacts of the project, the final EIS should include revised ambient concentration modeling results for any parameter and "objective duration" (e.g. $\leq$ 24 hours) for which a start-up scenario is the worst-case scenario. 6

- **Airshed Emissions Context:** The DEIS presents estimated expected annual emissions attributable to the project, for several parameters. The final EIS would be more conducive to decision-making if these estimates were presented in the context of the estimated total emissions (for each parameter) in the Lower Fraser Valley / Whatcom County airshed. For example the final EIS might indicate the percentage of airshed emissions that the project would represent, similar to what the DEIS presently does for greenhouse gas emissions. These estimates are available from the Greater Vancouver Regional District's July 2003 *Forecast and Backcast of the 2000 Emission Inventory for the Lower Fraser Valley Airshed 1985-2025.* 7

- **Mitigation Measures**

  PM Emissions: Applicant's proposal to reduce refinery emissions through removal of existing refinery boilers will offset the emission of some Criteria Air Contaminants. On page 3.2-46, the DEIS states:

  Enforceable conditions requiring removal of the refinery's three utility boilers within six months of the beginning of cogeneration facility operation could allow regulatory agencies to more fully take into account refinery emission reductions in the permitting and environmental review process.

  To facilitate decision-making concerning this potential requirement, the final EIS could include revised worst-case ambient concentration modeling results for the above scenario (i.e. post removal of refinery boilers). 8

  The largest expected emissions reduction will be in NO_x emissions resulting in net reduction of 318 tons per year. $PM_{2.5}$ emissions, however, which are linked to respiratory and circulatory diseases in humans, are expected to increase by 232 tons annually. This is a significant increase when compared to the overall $PM_{2.5}$ emissions in the airshed, and will result in some increase in ambient $PM_{2.5}$ concentrations. The Applicant proposed no mitigation measures to minimize the impacts of PM emissions from the operation of the proposed power plant. 9

  Greenhouse Gas Emissions: As proposed, the project would emit more than two million tons per year of greenhouse gases to the atmosphere. The proponent company has committed itself to greenhouse gas emission reduction targets on a worldwide basis and proposed to offset GHG emissions from this project as part of BP's corporate (worldwide) GHG objective. Also, the Applicant provided an alternate GHG mitigation proposal for the cogeneration facility that would apply to the project if the facility changes ownership. Whether the facility ownership remains with BP or changes, a credible/verified documentation would help ensure that such offsets are occurring. While it is recognized that climate change is a global concern, local air quality benefits as well as other environmental and economic benefits could be realized by offsetting greenhouse gas emissions locally, within the airshed. 10

A more detailed analysis of the DEIS and air quality related concerns/comments are provided in Attachment-A.

Comments on the BP Cherry Point Cogeneration Project - Draft Environmental Impact Statement
October 29, 2003

Attachment-A: Detailed Comments on the BP Cherry Point Cogeneration Project – Draft Environmental Impact Statement

The following findings are based on the review of the air quality section (3.2) of the Draft Environmental Impact Statement, pre-filed testimony of Brian R. Phillips (Exhibits 22.0, 22.1, 22.2, and 22.3), and discussions with the Applicant and their air quality consultant.

Overview of Maximum Potential and Expected Emissions

The following table summarizes the maximum potential emissions from the proposed power plant as well as the emission reductions (offsets) from the refinery that would result from the retirement of the existing steam boilers that currently supply steam to refinery processes.

Table 1.

	Maximum Potential Emissions (tons/y)				
	NO_x	**CO**	**VOC**	**PM_{10}**	**SO_2**
Power Plant Total[1]	233	158	42	262	51
Emission Reductions from Refinery[2]	-499	-54	-3	-10	-7
Net Emissions	**-266**	**104**	**39**	**252**	**44**

[1]Including emergency generator, firewater pump and cooling tower

[2]Note that the reductions from the refinery are based on the emission capacity of the refinery boilers, and not the emissions from current boiler operations.

The following table summarizes the emission of common air contaminants from the proposed power plant (maximum potential and expected), Sumas Energy 2, BP Cherry Point refinery, Whatcom County and the Lower Fraser Valley International Airshed.

Table 2.

	Emissions Comparison (tons/year)					
	NO_x	**CO**	**VOC**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**
BP Cherry Point Cogeneration Project (**Max. Potential**)[1]	-266	104	39	252	252	44
BP Cherry Point Cogeneration Project (**Expected-I**)[1, 2]	-318	27	25	232	232	43
BP Cherry Point Cogeneration Project (**Expected-II**)[1, 2, 3]	-318	27	25	84	84	43

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Sumas Energy 2 Generation Facility (**Max. Potential**)	145	88	153	209	209	69
BP Cherry Point Refinery (2000)	2,265	362	1,519	91	65	1,735
Emission Reductions from Refinery[4]	-499	-54	-3	-10	-10	-7
Whatcom County (2000)	17,400	114,650	40,280	5,300	2,540	10,060
Lower Fraser Valley International Airshed[5] (2000)	99,900	481,930	111,200	15,360	8,960	18,900

[1] Emission reductions (offsets) from the refinery due to the removal of refinery steam boilers are taken into account for both the "maximum potential" and the "expected" emission scenarios.

[2] "**Expected-I**" emissions are based on operating conditions that are considered more representative of actual operation of the cogeneration plant where "PM adjustment" was not taken into account. Interagency Technical Review Team does not support the inclusion of "PM adjustment" in emissions unless scientific documentation from reputable sources such as US EPA is provided.

[3] "**Expected-II**" emissions are based on operating conditions that are considered more representative of actual operation of the cogeneration plant where also the "PM adjustment" (-149 tpy) is taken into account. The Applicant claims that there is 60% error in the EPA test reference method that overestimates PM emissions from natural gas-fired turbines.

[4] Potential emission reductions due to removal of refinery steam boilers.

[5] Includes emissions from the GVRD, FVRD and Whatcom County.

The NO_x emissions are expected to be reduced with this project under both "Maximum Potential" and "Expected" operating conditions. This is mainly due to the retirement of existing refinery boilers that no longer will be needed when the cogeneration plant (providing the required steam for the refinery processes) begins operating. Emissions of all other common (criteria) air contaminants (CACs), however, are expected to increase with the cogeneration project. Emissions of carbon monoxide (CO), volatile organic compounds (VOCs) and sulphur oxides (SOx) are very low when compared to local emissions as well as the overall airshed emissions. Therefore, no significant direct air quality impacts of these contaminants are expected in Canada. This is confirmed by the modelling which shows the predicted ambient concentrations to be very low compared to Canadian objectives. Particulate Matter (PM) emissions, however, appear to be significant – under both "Maximum Potential" and "Expected" conditions – and deserve special attention. 11

PM Emissions

The proponent has included two different "expected" emissions scenarios for Particulate Matter. The first scenario assumes that the expected PM emissions will be 232 tpy (as shown in the table above). The second is known as the "PM adjustment" scenario which assumes that there is a 60% error (149 tpy) in the EPA test reference method and that the expected PM emissions will be 84 tpy (including refinery reductions) instead of 232 tpy. While the *Inter-Agency Technical Review Team* acknowledges the documentation provided by the proponent with respect to the accuracy of EPA Method PRE-4/202, it is the view of the *Team* that without additional scientific documentation from peer-reviewed third party sources or the EPA to support the evidence of error in the EPA test reference method, we will continue to evaluate the expected emissions from this facility without the PM adjustment. **11 cont.**

"Expected" PM_{10} emissions of 232 tons per year would increase the overall Whatcom County and Lower Fraser Valley International Airshed (PM_{10}) emissions by 4.4% and 1.5 %, respectively. Assuming all PM is released in the form of $PM_{2.5}$ the increase in the $PM_{2.5}$ emissions would be as high as 9% and 3% of the overall emissions of $PM_{2.5}$ for Whatcom County and the Lower Fraser Valley International Airshed, respectively. **12**

Overview of Secondary PM and Air Quality Issues

Secondary PM

The proponent has addressed the impact that the facility will have on secondary particulate matter (PM) formation. The sensitivity of the assumptions made about the percentage of NO_x and SO_x that gets converted to secondary particulate matter is significant to this issue. Depending on which conversion rate is used and whether 60% PM adjustment (-149 tpy) is taken into account, there can be a net decrease (-81 tpy) or a net increase (224 tpy) in overall (primary plus secondary) PM. If the "PM adjustment" is not taken into account, the overall PM balance is expected to range between 68 and 224 tpy (see table below). As stated previously, it is the view of the Team that "PM adjustment" should not be taken into account unless credible, scientific documentation (e.g. from US EPA) is provided. **13**

The *Inter-Agency Technical Review Team* discussed this issue with BP representatives in their meeting on January 29, 2003 and gave input with respect to conversion rates. It was felt that a range of conversion rates (~2% to 40%) should be examined in the final EIS to address the lack of literature on the subject and the uncertainty contained within the conversion rate assumptions. For the entire facility, there is a net decrease in NO_x and a net increase in SO_x (see "expected" emissions in the table above). Therefore, if a high conversion rate is used - as given in the DEIS (33% for NO_x, 20% for SO_x) - it will result in a large reduction in secondary PM from NO_x sources, but an increase in secondary PM from SO_x sources, resulting in a large net reduction in secondary PM and an increase of 68 tpy in overall PM balance. If a lower conversion rate, as suggested by the *Inter-agency Technical Review Team*, is used (10% for NO_x, 10% for SO_x), a net increase of 185 tpy in overall PM (primary plus secondary) would be expected from this facility. As shown in the following table, lower conversion rates (from NO_x and SO_x to secondary PM) would result in a higher overall PM balance. **14**

Table 3. Overall PM Balance for Three Different Scenarios/Conversion Rates

	Expected PM Emissions (tons/year)	Secondary PM from NOx (tons/year)	Secondary PM from SOx (tons/year)	Overall PM Balance (tons/year)
Conversion Rate: 33 % NOx and 20 % SOx				
Power Plant Total	242	104	21	367
Refinery Reductions	-10	-286	-3	-299
Net	**232**	**-182**	**18**	**68**
Conversion Rate: 10 % NOx and 10 % SOx				
Power Plant Total	242	31	10	283
Refinery Reductions	-10	-87	-1	-98
Net	**232**	**-56**	**9**	**185**
Conversion Rate: 2 % NOx and 4 % SOx				
Power Plant Total	242	6	4	252
Refinery Reductions	-10	-17	-1	-28
Net	**232**	**-11**	**3**	**224**

*It is assumed that NO_x emissions are 181 tpy (plus a refinery reduction of -499), and SO_x emissions are 51 tpy (plus a refinery reduction of -7 tpy). Also, no "PM adjustment" was taken into account. Secondary PM is assumed to be ammonium nitrate and ammonium sulphate.

Ambient PM Concentrations

Modelled concentration for maximum 24-hour PM_{10} and $PM_{2.5}$ in Canada (location with maximum impact) is 2.5 $\mu g/m^3$. The worst-case increase in the 24-hour ambient PM_{10} concentration at a Canadian location was less than 7% over worst-case background at the same location. Maximum change in 24-hour PM_{10} concentrations for White Rock (0.52 $\mu g/m^3$), Langley (0.36 $\mu g/m^3$), Richmond (0.19 $\mu g/m^3$), and Abbotsford (0.16 $\mu g/m^3$) are predicted to be much lower than for the Canadian location with maximum impact (Table 5). A maximum annual PM_{10} concentration of 0.2 $\mu g/m^3$ was also predicted for the same location close to the Canada/US border. These concentrations are based on maximum potential emissions and did not

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take into account any "PM adjustments" or secondary PM formation/reduction into account. The modelled increases in the ambient PM_{10} levels do not appear to be high for major residential areas.

Table 4. Comparison of Maximum PM_{10} Concentrations in Canada (BP vs. SE2)

Facility Name	Averaging Time	Maximum PM_{10} Concentration in Canada[1, 2] ($\mu g/m^3$)			Most Stringent Canadian Objective ($\mu g/m^3$)
		Change	Background	Total	
BP Cherry Point Cogen. Project	**24-Hr**	2.5	39*	42*	50
	Annual	0.2	13	13	30
Sumas Energy 2 Generation Facility	**24-Hr**	3.7	52	56	50
	Annual	0.4	15	15	30

* These numbers are revised using GVRD data
[1] BP Cherry Point: Highest concentrations in Canada predicted on the US/Canada border, 12 km north of project site. Source of data is DEIS (September 2003)
[2] Sumas Energy 2: highest concentrations in Canada predicted on Sumas Mountain, Abbotsford. Source of Data is SE2 Second Revised Application (June 2001)

Table 5. Increase in Maximum PM_{10} Concentrations (BP Cherry Point Project)

Averaging Time	Increase in Maximum PM_{10} Concentrations at Various Locations* ($\mu g/m^3$)					
	Max. US	Max. Canada	White Rock	Langley	Richmond	Abbotsford
24-Hr	4.3	2.5	0.52	0.36	0.19	0.16
Annual	0.25	0.2	0.06	0.04	0.01	0.01

*Data in this table is based on information provided by the proponent at a meeting with the Interagency Technical Review Team on September 15, 2003.

Results of Calpuff modelling with secondary PM formation (i.e. 24-hour isopleths and maximum concentration) should be provided, in order to determine the combined effect of primary and secondary PM on ambient air quality. Current values reported in the DEIS are from the ISC modelling, which doesn't include secondary PM. **16**

Ambient Ozone Concentrations

Notably, the DEIS does not comment upon or address the impact of the proposed facility on ozone concentrations. Known to pose a health risk at current levels, ozone is a priority air quality issue in the LFV airshed and has been the focus of several scientific investigations and federal, provincial and regional air quality management initiatives. **17**

Start-Up Scenarios

The DEIS modeled worst-case Canadian ambient concentrations of several pollutants. It is our understanding that these worst cases were defined from "maximum potential emission" scenarios, but that these scenarios did not include start-up scenarios. Additional information **18**

received from the proponent subsequent to the release of the DEIS suggests that for some parameters (e.g. nitrogen oxides and carbon monoxide), the worst-case scenario for short-term exposures in Canada may be a start-up scenario. Therefore we conclude that in order to most accurately describe the environmental impacts of the project, the final EIS should include revised ambient concentration modeling results for any parameter and "objective duration" (e.g. ≤ 24 hours) for which a start-up scenario is the worst-case scenario. **18 cont.**

Health Effects

There is a substantial and growing body of evidence that suggests that adverse health effects would be predicted at particulate matter (less than 2.5 microns) and ozone exposure levels currently experienced in the Lower Fraser Valley, below current air quality objectives. For example, Bates et al (2003) concluded that: *"Levels of some air pollutants, particularly $PM_{2.5}$ and its wood smoke component, and ozone, in British Columbia are at levels which, on the basis of comparisons with international data, would be predicted to be causing adverse health effects,"* and went on to recommend that: *"...any improvement in air quality for PM or ozone would result in fewer negative health impacts."* Bates, D.V., Brauer, M., Koenig, J. Q., *Health and Air Quality 2002 – Phase 1 – Methods for Estimating and Applying Relationships Between Air Pollution and Health Effects*, British Columbia Lung Association, 2003.

In 2001, Lower Fraser Valley Medical Health Officers stated that:
"Air pollution is an important public health issue and is linked to illness and death in the lower mainland and elsewhere. This is true despite the fact that current levels of air pollution in the lower mainland are generally stable or lower than they have been in the past and that levels of air pollution in the lower mainland are lower than other major cities in western North America." Copes, R., Blatherwick, J., Guasparini, R., Loewen, N., O'Connor, B., *Air Quality in the Lower Mainland: Patterns, Trends and Human Health*, South Fraser Health Region, 2001.

Vedal et al (2003) concluded from an analysis of data from Vancouver, British Columbia, between 1994 and 1996 that *"increases in low concentrations of air pollution are associated with increased daily mortality."* Vedal, S., Brauer, M., White, R., and Petkau, J., *Air Pollution and Daily Mortality in a City with Low Levels of Pollution*, Environmental Health Perspectives, 111:1, 2003.

The body of evidence above suggests that the worst-case increases in ambient PM concentrations associated with the project would be statistically expected to lead to adverse health effects among some Canadian residents. **19**

Mitigation Measures

Section 3.2.7 in the DEIS describes the Applicant's proposal to mitigate air emissions during the construction and operation of the energy facility. Construction emissions will be limited to fugitive dust and emissions from construction equipment powered by gasoline and diesel **20**

engines. These emissions appear to be small and will only occur during the construction phase of the project. Emissions resulting from the operation of the power plant, however, appear to be significant (PM_{10} and/or $PM_{2.5}$ in particular) and should be addressed through proper mitigation measure. **20 cont.**

Selective Catalytic Reduction (SCR) – The SCR technology will potentially reduce the NO_x emissions from 9 ppm to 2.5 ppm by using ammonia. In addition to being toxic, the introduction of ammonia emissions (175 tons per year) through SCR has the potential to contribute to secondary PM formation in the atmosphere. This is considered as the major drawback of the proposed SCR technology. **21**

Refinery Steam Boilers – The cogeneration facility will provide steam for the refinery processes that are currently met by existing refinery steam boilers. Reducing the refinery emissions through removal of existing refinery boilers will help offset some of the Criteria Air Contaminant emissions. The largest reduction will be in NO_x emissions resulting in a net reduction of 318 tons per year.

On page 3.2-46, the DEIS states: "*Enforceable conditions requiring removal of the refinery's three utility boilers within six months of the beginning of cogeneration facility operation could allow regulatory agencies to more fully take into account refinery emission reductions in the permitting and environmental review process.*" **22**

To facilitate decision-making concerning this potential requirement, the final EIS could include revised worst-case ambient concentration modeling results for the above scenario (i.e. post removal of refinery boilers).

Cogeneration Plant – The operation of the cogeneration facility is expected to increase $PM_{2.5}$ emissions by 232 tons per year under "actual" (or likely) operating conditions. This is a significant increase when compared to the overall $PM_{2.5}$ emissions in the airshed and can be expected to result in some increases in ambient $PM_{2.5}$ concentrations. Although fine particulate matter ($PM_{2.5}$) are linked to respiratory and circulatory diseases in humans and considered the most harmful among the criteria air contaminants (CACs), the Applicant proposed no mitigation measures to minimize the impacts of PM emissions from the operation of the proposed power plant. EFSEC's Site Certification Agreement required a similar facility (Sumas Energy 2) to offset 100% of particulate (PM) emissions from their operation. Offsetting $PM_{2.5}$ emissions would help manage these harmful emissions and associated ambient impacts in our airshed where approximately 2.5 million people live. **23**

GHG Mitigation – According to the data provided in the DEIS (Table 3.2-25), the greenhouse gas emissions from the cogeneration project would be 5%, 37%, 58% and 61% lower than a natural gas fueled combined cycle combustion turbine, and conventional natural gas-fired, oil-fired and coal-fired boilers, respectively. This is mainly due to more efficient fuel utilization achieved by combined-cycle cogeneration plants as well as the use of a less carbon intensive fuel such as natural gas.

The Applicant proposed to mitigate the project's greenhouse gas emissions as part of BP's corporate GHG objective within the company's worldwide operations. BP's worldwide objective is to hold its net GHG emissions at the 2002 level through the year 2012. If the proposed

cogeneration facility changed ownership in the future an alternate GHG mitigation scheme would apply. According to this proposal GHG reductions would be obtained by the facility owner or would be provided in the form of an annual payment to a qualifying organization (e.g. the Climate Trust) for 30 years, which is the assumed economic life of the project. This would offset approximately 20% of the greenhouse gases generated by this project. According to the DEIS, BC Hydro plans to offset 50% of GHG emissions from new natural gas fired power plants, and Seattle City Light targets 100% offset for all new fossil generating stations added to the City's energy mix.

Whether the facility ownership remains with BP or changes, EFSEC should ensure that a credible, verified documentation be provided for GHG offsets. Since offsetting greenhouse gas emissions within the airshed would offer additional local air quality benefits as well as other environmental and economic benefits, preference should also be given to local GHG offsets. **24**

Section 3.2.8 Significant Unavoidable Impacts: It is stated in the DEIS that "No significant unavoidable adverse impacts on air quality are identified." This project, however, has the potential to increase fine particulate ($PM_{2.5}$) emissions, which are linked to respiratory and circulatory diseases in humans, by 232 tons per year. The increase in PM emissions can be expected to result in some increases in the ambient concentrations of fine particulate. In addition, over 2 million tons of greenhouse gas emissions will be emitted from this project, annually. These would result in some unavoidable environmental impacts, unless the $PM_{2.5}$ (fine particulate) and the greenhouse gas emissions are offset properly. **25**

Specific Comments on the Air Quality Section (Section 3.2) of the DEIS:

Table 3.2-4 (p. 3.2-11) contains several errors which were discovered upon review of the Greater Vancouver Regional District's annual air quality reports for the years noted in the table. For ambient monitoring station 1, the 24-hour PM_{10} for 2001 is 39 (not 35), the 24-hour $PM_{2.5}$ for 2001 is 21 (not 19), and the 24-hour ozone for 2001 is 80 (not 76). For ambient monitoring station 2, the 24-hour $PM_{2.5}$ for 2001 is 19 (not 17) and the 24-hour ozone for 2001 is 84 (not 82). In the maximum column, 24-hour PM_{10} should be 39 (not 35), 1-hour CO should be 4060 (not 2900) and 1-hour ozone should be 166 (not 168). Of main significance is the increase in the maximum 24-hour PM_{10} to 39 $\mu g/m^3$. **26**

Table 3.2-5 (p. 3.2-13) presents a summary of the GVRD air quality index based on a dataset limited to only one year. We feel it is more appropriate to consider at least three years of ambient air quality data for establishing current conditions, as is done in Table 3.2-4. **27**

There is an apparent disagreement between Tables 3.2.8 and 3.2.9, regarding sulfur dioxide and carbon monoxide concentrations. If this is not a true disagreement, then additional clarification would be helpful. **28**

Table 3.2-15 and Table 3.2-16 (p. 3.2-25) should also include the maximum 24-hour $PM_{2.5}$ concentrations in addition to the 98^{th} percentile concentrations currently reported in the tables. **29**

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Table 3.2-20 (p. 3.2-28) – Net Regional Change in [PM_{10}] Emissions is listed as -84. This should be corrected as +84. Also, this table needs to be re-organized to clarify the relationship between the rows (i.e. row 3 is the summation of row 1 and row 2; row 5 is the summation of row 3 and row 4). **29 cont.**

Table 3.2-23 (p. 3.2-31) is confusing as presented. It is suggested that this table be re-organized to show the relationship between the rows (e.g. row 3 is the sum of row 1 and row 2, etc.). In addition, the effects of NO_x and SO_2 emissions/reductions on secondary particulate are calculated assuming that a one ton emission/reduction in NO_x or SO_2 results in a one ton change in secondary PM. It would me more appropriate to consider molecular weights in this determination, and to assume that the secondary PM is in the forms of ammonium nitrate and ammonium sulphate. **30**